

**DIRECT TESTIMONY OF**  
**GREGORY M. LANDER**  
**ON BEHALF OF**  
**SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND**  
**SOUTHERN ALLIANCE FOR CLEAN ENERGY**  
**DOCKET NO. 2020-1-E**

**INTRODUCTION**

1     **Q.     Please state your name, business address, and employment.**

2     A.     My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101,  
3           West 3 Peabody, MA 01960, and my email address is  
4           [glander@skippingstone.com](mailto:glander@skippingstone.com). I am President of Skipping Stone, LLC (“Skipping  
5           Stone”).

6     **Q.     On whose behalf are you testifying?**

7     A.     The South Carolina Coastal Conservation League (“SCCCL”) and the Southern  
8           Alliance for Clean Energy (“SACE”).

9     **Q.     What is your educational and professional background?**

10    A.     I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a  
11           Bachelor of Arts degree. In 1981, I began my career in the energy business at  
12           Citizens Energy Corporation in Boston, Massachusetts (“Citizens Energy”). I  
13           became involved in the natural gas business of Citizens Energy in 1983. Between  
14           1983 and 1989, I served as Manager, Vice President, President and Chairman of  
15           Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and

1 ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during  
2 which time I consulted on numerous pipeline open access matters, a number of  
3 Federal Energy Regulatory Commission (“FERC”) Order No. 636 rate cases,  
4 pipeline certificate cases, fuel supply and gas transportation issues for  
5 independent power generation projects, international arbitration cases involving  
6 renegotiation of pipeline gas supply contracts, and natural gas market information  
7 requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded  
8 TransCapacity LP, a software and natural gas information services company.  
9 Since 1994, I have also been a Services Segment board member of the Gas  
10 Industry Standards Board (“GISB”) and its successor organization, the North  
11 American Energy Standards Board (“NAESB”). During the period 1994 to 2002,  
12 I served as a Chairman of the Business Practices Subcommittee, the  
13 Interpretations Committee, the Triage Committee, and several GISB/NAESB  
14 Task Forces.

15 I am currently a Board Member of NAESB and have served continuously  
16 in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999,  
17 and since that time I have headed up Skipping Stone’s Energy Logistics practice,  
18 where my specialization has been interstate pipeline capacity issues, information,  
19 research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone  
20 launched CapacityCenter.com, a pipeline capacity information service. In 2004,  
21 Skipping Stone was acquired by Commerce Energy Group, a national retail  
22 energy services provider. In 2005, I was appointed President of Skipping Stone,  
23 which operated as a wholly owned subsidiary of Commerce Energy Group. In

1           2008, I purchased substantially all of the assets of Skipping Stone and now  
2           operate essentially the same business as before the Commerce Energy transaction  
3           as Skipping Stone, LLC.

4           From 1984 to present, I have maintained a deep familiarity with a wide  
5           range of pipeline transportation issues, beginning with access to pipeline capacity  
6           to make competitive sales, resolution of the pipeline take-or-pay contracting  
7           regime, pipeline affiliate marketer concerns, restructuring of the pipelines from  
8           merchants to transporters and thereafter, and definitions of what constituted a  
9           pipeline capacity “right” for the purposes of formulating the then newly  
10          commenced capacity release and capacity rights trading business process. I  
11          continue to be involved in nearly all facets of the capacity information and trading  
12          business as part of my duties at Skipping Stone. In addition, I have been the lead  
13          principal on all 50 plus pipeline and storage mergers and acquisitions transactions  
14          as well as all pipeline and storage facility expansion projects for which Skipping  
15          Stone has been retained by potential purchasers and project sponsors to provide  
16          economic due diligence consulting and market analysis. One of the many  
17          transactions I worked on for a potential purchaser client was SCANA’s sale of  
18          Carolina Gas Transmission, now Dominion Energy Carolina Gas Transmission  
19          (DEC GT).

20       **Q.    Have you filed testimony in regulatory proceedings previously?**

21       A.    I have filed testimony in several proceedings including FERC Docket No. RP04-  
22           251-000, which was an El Paso Natural Gas Company (“EPNG”) proceeding  
23           regarding pathing and segmentation. In FERC Docket No. RP08-426-000 (also an

EPNG proceeding), I sponsored answering and supplemental answering testimony. I also filed testimony in FERC Docket No. RP10-1398, the first fully litigated EPNG Rate case in more than three decades. In addition, I have filed testimony in Massachusetts Department of Public Utilities Case Nos. 13-157, 15-34, 15-48, and 15-39; Maine Public Utilities Commission Case No. 2014-00071; Virginia Corporation Commission Case Nos. PUR-2017-00051, PUR-2018-00065, PUR-2019-00070 and PUR-2020-00031; Missouri Public Service Case GR-2017-0215; GR-2017-0216; California Public Utilities Commission Cases 17-10-007 and 17-10-008 (Consolidated) Applications of San Diego Gas & Electric (U902M) and Southern California Gas Company (U 338-E) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019; South Carolina Public Service Commission Docket Nos. 2017-370-E; 2017-305-E; 2017-207-E, 2019-2-E, 2019-3-E and 2020-2-E; New York Public Service Commission Docket Nos. Case 19-G-0066, Case-19-0309, and Case 19-0310; and, FERC Docket No. ER18-1639. Please refer to Exhibit 1 for my current CV and Exhibit 2 for a full list of case names.

### **EXECUTIVE SUMMARY**

**Q. What do you address in your testimony?**

**A.** My testimony covers four topics:

1. The load factor utilization of Duke Energy Progress' ("DEP") and Duke Energy Carolinas' (together, the "Companies") existing contracted natural gas pipeline capacity over the review period;<sup>1</sup>

---

<sup>1</sup> Because of the nature of their operations and the manner in which they provide their data, it is infeasible to separate the Companies' operations or assets for the purposes of the analysis in this testimony.

2. The sufficiency of the Companies' existing capacity to serve its combined cycle plants and peaker plants;
3. Recommendations related to the apparent lack of monetization of the Companies' idle pipeline capacity when demand for gas-fired generation is less than contracted firm capacity; and
4. Recommendations for the Commission to require more useful Companies-supplied data in future Fuel Factor proceedings and to allow additional time between the filing date for Company direct testimony and the deadline for other parties' direct testimony.

With respect to this last item, the Companies'-provided data makes cross-referencing data between responses and holistically evaluating the Companies' performance unnecessarily difficult. For example, in its responses, DEP listed the same plants by different names in different responses, omitted units from some responses, and often did not distinguish between combined cycle and combustion turbine facilities at the same pipeline delivery location. To highlight some of these flaws, I provide four tables in the Appendix which show the differing plant names used by the Companies in different responses.

#### **I. LOAD FACTOR UTILITIZATION ANALYSIS**

**Q: Please begin by defining what you mean by load factor utilization in your analysis?**

**A:** I'm referring to the extent to which the Companies' made use of their long-term contracted firm capacity over the review period. Contracts for long-term firm capacity come with substantial fixed costs that are paid without regard to the level of use of the contracted capacity. The higher the load factor percentage the better

1 the utilization of long-term contracted capacity. A high load factor utilization of  
 2 firm capacity indicates that the Companies' have made prudent use of ratepayer  
 3 dollars in procuring such capacity.

4 **Q: Please describe how you analyzed the Companies' load factor utilization of**  
 5 **its firm pipeline contracts.**

6 A: To evaluate the load factor use of the Companies' firm capacity to fire its  
 7 combined cycle and other gas-fired plants, I first analyzed and processed the  
 8 hourly flow data provided by DEP to determine daily (24 hour) deliveries.<sup>2</sup> I then  
 9 compared these quantities to the Companies' contracted Transco capacity data.<sup>3</sup>

10 **Q: What did your analysis find?**

11 A: I determined that the Companies' utilization of their existing long-term capacity  
 12 inventory (as distinct from total winter capacity) during the review period  
 13 exceeded 71 percent. This is a very good level of utilization. During the winter  
 14 months, utilization of long-term contracted capacity was particularly high. For  
 15 four of the five winter months of the review period, DEC and DEP together had  
 16 453,339 Dth per day (Dth/d) of capacity on Transco, of which 434,650 Dth/d  
 17 (95.9 percent) is long-term contracted capacity.<sup>4</sup>

18 **Q: Why did you calculate utilization for the winter period specifically?**

19 A: The winter period is particularly important with respect to capacity sufficiency. In  
 20 the winter, local distribution companies ("LDCs") (which, as a class, are some of

<sup>2</sup> See Companies' Response to ER 1-7.

<sup>3</sup> See Companies' Response to ER 1-6. Also note that Companies' interstate contracted capacity and short-term capacity release data is publicly available per FERC regulations.

<sup>4</sup> For the month of March 2019, an additional 25,239 Dth/d of capacity was obtained by the Companies in the short-term capacity release market. This is depicted as the bumpy peaks on the load duration versus contracted capacity chart (see Chart 1).

1 the largest pipeline capacity users) often have their peaks at the same time of day  
 2 that electric generators have their winter peak loads. The simultaneity of these  
 3 demands puts stress on the pipelines and the LDCs. The problem can be  
 4 especially acute when the power plants are located inside of the LDCs'  
 5 distribution networks. In such instances, these simultaneous peak demands can  
 6 make it difficult for LDCs to provide swing services to power plants to cover their  
 7 short-term swings in demand.

8 **Q: Was the Companies' peak during the winter period?**

9 A: Yes. Looking at daily data derived from summing each day's hourly flow data, I  
 10 determined that the Companies had a peak gas day on [REDACTED]  
 11 [REDACTED].<sup>5</sup> While this day is not in "deep winter," which is  
 12 January and February in the Carolinas, it does fall within the winter period used  
 13 by pipelines and LDCs, which runs from November 1 through March 31.<sup>6</sup>

14 **Q: How did you arrive at this peak winter gas day figure?**

15 A: I summed daily data from the three pipelines with which the Companies  
 16 contract—Transco, Public Service North Carolina ("PSNC"), and Piedmont.  
 17 Since both PSNC and Piedmont receive all or most of their gas from Transco, I  
 18 also calculated the Companies' peak day and quantity with respect to Transco  
 19 alone.<sup>7</sup> The Companies' peak day for Transco alone was also on [REDACTED]  
 20 [REDACTED]. Both the peak flow quantity for all three

<sup>5</sup> This data was provided by the Companies in response to ER 1-7. For a sample of this data in the form it was provided, see GML Exhibit 4, which is a print-out of the first two pages of Attachment ER 1-7.

<sup>6</sup> Note that the review period starts with the last month of winter (March), extends through the non-winter months of April through October, and finishes with the remaining winter months of November through February.

<sup>7</sup> Part of the Piedmont service territory in northeastern North Carolina has contracts with Columbia Gas Transmission for deliveries to the former NC Natural Gas totaling 25,000 Dth/d, but the remainder comes from Transco.

1 pipelines combined [REDACTED] and for Transco alone [REDACTED] exceed  
2 the Companies' contracted firm Transco pipeline capacity during the review  
3 period, which was 453,339 Dth/d. These comparative peak daily flow and daily  
4 capacity figures are discussed again below.

5 **Q: On any given day, when the Companies' gas needs exceed quantities**  
6 **available under its long-term contracts, how do they go about procuring the**  
7 **necessary supplies?**

8 A: Deliveries in excess of firm contracted capacity are effectuated by the Companies  
9 using either: (a) short term contracted firm capacity (e.g. capacity release);<sup>8</sup> (b)  
10 segmentation of existing contracted capacity;<sup>9</sup> (c) the Companies' contracts for  
11 interruptible capacity; or (d) the capacity held by sellers of gas to the Companies'  
12 plants.

13 **Q: Is short-term capacity reflected in the 71 percent load factor utilization cited**  
14 **previously?**

15 A: No. Daily use of gas above long-term contracted levels does not increase the load  
16 factor utilization of long-term capacity.

17 **Q: Did you evaluate the Companies' load factor utilization for its total**  
18 **contracted capacity, both short-term and long-term?**

19 A: Yes. I determined that the Companies' load factor utilization of all contracted  
20 capacity was 64 percent, which, if 64 percent were the level of utilization of long-  
21 term capacity, would still be a good level of overall utilization. However, the

---

<sup>8</sup> Short-term capacity release enables capacity to be acquired as close to flow as hours before flow or such capacity can be acquired days, weeks, months, or even years prior to flow.

<sup>9</sup> While segmentation of existing long-term capacity would increase load-factor utilization of such capacity, the data provided by DEP did not permit determination of whether segmentation was used to make deliveries to any of its plants.

1 Companies' overall load factor utilization is dampened by its suboptimal use of  
 2 acquired short-term capacity.<sup>10</sup> While the Companies acquired short-  
 3 term capacity totaling 19.16 million Dths over the review period,<sup>11</sup> only [REDACTED]  
 4 [REDACTED] of this short-term capacity was actually delivered (used). Thus, the load factor  
 5 utilization of these short-term contracts was just [REDACTED]. The Companies also  
 6 used or were supplied an additional [REDACTED] above and beyond the  
 7 combination of their long-term and short-term capacity contracts via one of the  
 8 other three methods mentioned above—segmentation, contracts for interruptible  
 9 capacity; or capacity held by sellers of gas to the Companies' plants.

10 **Q: Does the low utilization of short-term capacity mean that it was imprudent**  
 11 **for the Companies' to secure so much short-term capacity?**

12 A: Not necessarily. The winter portion of the added short-term capacity did have  
 13 reasonably good daily utilization during the winter period, which as I've noted, is  
 14 the more critical period for gas supplies. Chart 1 below is a winter and non-winter  
 15 load duration curve that plots load (deliveries of gas) against contracted capacity.  
 16 It gives the viewer an insight into "used" versus "contracted," and from the  
 17 numbers behind the curves and lines, load factor utilization can be calculated. The  
 18 very far left of the chart depicts the high demand days of the winter period. This  
 19 was the only part of the year when daily delivered quantities exceed daily  
 20 contracted quantities – i.e. the jagged black line (total contracted capacity) is  
 21 above the blue line (long-term capacity) and below the green line (the actual daily

<sup>10</sup> As can be seen from Chart 1, the acquired short-term non-winter capacity went essentially unutilized. The sloping green line (daily use) is below both the blue line (long-term contracted) and the jagged black line (sum of long-term plus short-term contracted).

<sup>11</sup> This amount was calculated by multiplying the Dth/d of short term capacity contracts by the duration of those contracts in days.

1 amount the Companies used over each period, sorted from highest to lowest).<sup>12</sup>  
 2 This means both: 1) that for those high demand winter days, the Companies made  
 3 very good use of their total contracted capacity; and, 2) that on only these few  
 4 days of the year did daily demand exceed daily contracted. Otherwise, however,  
 5 the Companies' load, or use of capacity, was far less than the contracted level of  
 6 capacity. As will be discussed below, the red line represents the maximum hour  
 7 quantities of each day turned into an indicative daily capacity equivalent of that  
 8 max hour (i.e., the max hour times 24) and then sorted from highest to lowest.  
 9 This metric is relevant to the sufficiency of capacity discussion in Section II  
 10 below.



11  
 12 **Chart 1.** Winter and Non-Winter Load Duration Curves Over the Review Period

13 **Q: What about for the non-winter months?**

14 In the non-winter months (April through October), the Companies similarly  
 15 supplemented their long-term firm capacity inventory (434,650 Dth/d) with short-  
 16 term acquisitions from the capacity release market. At its peak, the Companies'  
 17 total non-winter contracted capacity reached 523,339 Dth/d. But as the above

<sup>12</sup> The purple curved line is the daily deliveries to plants associated with the Transco "pipeline" sorted from highest to lowest for each of the winter and non-winter periods.

1 chart depicts, the Companies' daily use of short-term contracted capacity was  
2 generally low.

3 **Q: What conclusions can you make with respect to load factor utilization?**

4 A: Overall, the Companies made good use of their long-term capacity but sub-  
5 optimal use of their short term acquisitions. In addition, DEP should be  
6 commended for providing the granular hourly data which complies with this  
7 Commission's order from last year's DEC fuel cost proceeding. Such granular  
8 data enabled my load factor analysis, as well as identification of daily and  
9 seasonal peak hour delivery amounts and timing. However, as discussed further  
10 below, the Commission should require the Companies to provide some additional  
11 data points and clarification.

12

13 **II. SUFFICIENCY OF CAPACITY TO SERVE**  
14 **COMBINED CYCLE UNITS**  
15

16 **Q: Did you analyze the sufficiency of the Companies' firm pipeline capacity to**  
17 **serve their combined cycle units?**

18 A: Yes, although my ability to do so was somewhat hampered by certain data  
19 deficiencies regarding combustion turbines and their fuel use. This additional  
20 information will better enable the Commission and intervening parties to assess  
21 the use and sufficiency of the Companies' contracted capacity. My specific  
22 recommendations in that regard are set forth in Section IV below.

23 **Q: Where did your analysis of the sufficiency of the Companies' firm pipeline**  
24 **capacity begin?**

25 A: With a calculation of the Companies' peak hour of capacity use.

1    **Q:    Why did you start there?**

2    A:    Because the hour is the interval at which having firm pipeline capacity matters.  
 3           While pipelines, and for the most part, LDCs, contract their firm capacity services  
 4           to their customers on a daily basis, it is pressure and *hourly* deliverability capacity  
 5           that really matters. When homeowners turn on their heat, the gas has to be there to  
 6           maintain the flame. Absent the pressure to maintain the flame, the pilot lights go  
 7           out, and when the pressure returns with no pilot light, catastrophic events may  
 8           ensue. The LDC must be able to maintain pressure and deliveries at the time of  
 9           day demanded, and this drives all other aspects of LDCs' planning and execution.  
 10          Because of this, unless a customer's contract specifies otherwise,<sup>13</sup> the  
 11          overwhelming majority of pipeline services only obligate the pipeline to provide  
 12          1/24<sup>th</sup> of daily quantities<sup>14</sup> in any given hour (a 4.16% hour). This 1/24<sup>th</sup> service  
 13          can also be termed a "ratable delivery service" or pro-rata hourly service.

14   **Q:    What was the Companies' peak hour of flow?**

15   A:    In my analysis, I identified the Companies' pertinent peak hour of flow and how it  
 16          related to this "1/24<sup>th</sup> hour." For the review period, the Companies' pertinent peak  
 17          hour was from [REDACTED]. Gas usage during that peak  
 18          hour was [REDACTED] Dth per hour (Dth/hr). If that peak hour were to be met solely by  
 19          pipeline capacity where the pipeline is enforcing only 1/24<sup>th</sup> hour takes by means

---

<sup>13</sup> For instance, a contract may specify a maximum hourly quantity or the contract's rate schedule may permit maximum hourly takes as a larger percentage of daily quantities.

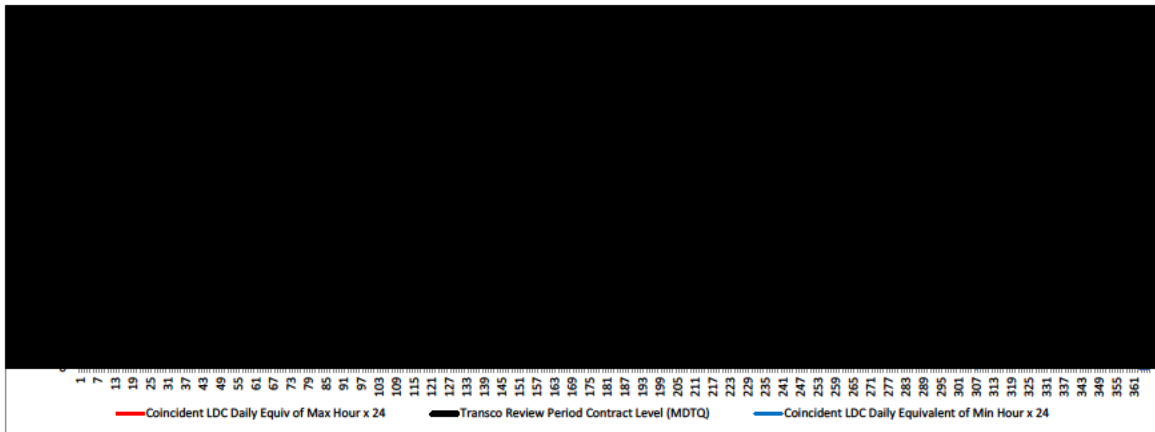
<sup>14</sup> Generally the terms of service only require the pipeline to receive and deliver 1/24<sup>th</sup> of daily requested quantities every hour of the Gas Day while variations from 1/24<sup>th</sup> are at the discretion of the pipeline provided they do not negatively impact firm service to another shipper. Thus, a requested quantity equal to maximum daily contract quantity only obligates the pipeline to provide 1/24<sup>th</sup> of that contract quantity each hour.

1 of operational flow orders<sup>15</sup> or flow-control, a customer needing to take that  
 2 amount of gas on a firm basis would have to have a firm contracted capacity of  
 3 [REDACTED]. The Companies contracted for  
 4 453,339 Dth/d of firm capacity in January of the review period. The 1/24<sup>th</sup>  
 5 quantity associated with the 453,339 Dth/d is 18,889 Dth/hr (453,339 divided by  
 6 24 = 18,889). To get to [REDACTED] Dth/hr from 18,889 Dth/hr, under the specified  
 7 pipeline operating conditions, would mean obtaining an additional [REDACTED] Dth/hr  
 8 of deliverability, or [REDACTED] Dth/d.

9 However, attempting to meet this demand using firm pipeline capacity  
 10 would be an extremely expensive option. Based on a rough estimate, the fixed  
 11 costs would be, on the low end, over \$75.2 million per year, and possibly as high  
 12 as \$250.9 million.<sup>16</sup> Moreover, the data shows that the Companies were able to  
 13 meet this hourly peak without additional firm capacity by using an assemblage of  
 14 other assets and supplies and by making use of LDC “swing services” (services  
 15 that LDCs provide to ensure availability during periods with high “swings” in  
 16 hourly usage). The chart below shows the difference in minimum and maximum  
 17 hourly daily flows; the difference between the jagged blue line and the sloping red  
 18 line shows the “swing” in usage that the Companies’ met with existing contracts,  
 19 services, assets and supplies.

<sup>15</sup> An Operational Flow Order or OFO is when the pipeline orders its contract holder(s) to specifically comply with a pipeline-specified flow rate or to perform in a manner that improves /reduces stress on pipeline operations.

<sup>16</sup> The first estimate is based off a low-cost rate of \$0.60 per Dth/d for new Transco Zone 5 to Zone 5 capacity (the minimum capacity path the Companies would have to acquire). Then, if the utility wanted to connect this new Transco Zone 5 capacity to Southwestern PA via the Atlantic Coast Pipeline later, at an estimated negotiated rate of \$1.40 per Dth/d, the combined fixed cost would be over \$250.9 million.



**Chart 2. Indicative Swing Management During Review Period**

**Q: Based on this, does it appear that the Companies need additional firm capacity?**

**A:** No. It is a fact that the Companies *did* meet demand during this peak hour and throughout the winter without obtaining additional firm capacity beyond that contracted for use during the review period. Moreover, should the Companies' firm pipeline capacity not enable such level of hourly flow, it could be met using other assets and supplies.<sup>17</sup> Based upon my review of the data, in my opinion there are sufficient assets available to, and used by, the Companies to provide sustainable, reliable service without increasing fixed costs to ratepayers. In short, the Companies are able to meet its capacity needs during these peak hours by means of existing contracts and facilities, as well as from LDC services which provide supplemental swing services.

### **III. MONETIZATION OF UNUSED CAPACITY**

<sup>17</sup> For example, "other supplies" could include fuel oil to the extent demand in excess of contracted capacity was caused by combustion turbines burning gas.

1     **Q:     Given that you have a generally favorable view of the Companies’**  
 2           **management of their contracts and capacity, do you have any**  
 3           **recommendations for how the Companies could improve?**

4     A:     Yes. While the Companies’ use of its capacity is at a relatively high load factor,  
 5           there are periods when it has idle pipeline capacity. It may be possible to save  
 6           ratepayers money by monetizing pipeline capacity that is idle for many days of  
 7           the year by selling it on the secondary capacity market.

8                     For instance, looking at the Companies’ actual daily use during the review  
 9           period, the Companies had at least 50,000 Dth/d of idle Transco capacity on a  
 10          total of 270 days during the review period (100 days during the winter period and  
 11          170 days during the non-winter period).<sup>18</sup> Based on the Companies’ 71 percent  
 12          load factor utilization, I calculated that the Companies had approximately [REDACTED]  
 13          [REDACTED] Dth of capacity unused. And, even taking an extremely conservative  
 14          approach, there were 150 days where, even if the Companies had burned the  
 15          equivalent of their max hour burn on that day for all 24 hours of the day, they still  
 16          would have had least 50,000 Dth sitting idle for the entire day. The amount the  
 17          Companies would have had available to sell under this example would be 7.5  
 18          million Dth (50,000 Dth/d for 150 days). If the Company had resold this capacity  
 19          on the secondary market, it could represent significant ratepayer savings.

20    **Q:     Did you calculate the ratepayer savings that would occur if the Companies**  
 21           **sold this idle capacity on the secondary market?**

22    A:     Yes. In the highly conservative example above, if the Companies sold 50,000  
 23          Dth/d for the 150-day period, ratepayers would save \$150,000 in total (assuming a

---

<sup>18</sup> And even greater quantities than 50,000 Dth/d on fewer days.

1 low-cost average price of two cents per Dth/d). But looking at the Companies'  
2 actual usage, had they Companies sold just [REDACTED] Dth of  
3 their contracted capacity that went unutilized during the review period (20.25  
4 million Dth), ratepayers would have benefitted by more than \$4 million in total  
5 (again, assuming a price of two cents per Dth).

6 **Q: Did the Companies take advantage of this opportunity to save ratepayers**  
7 **money?**

8 A: No. I reviewed all capacity release transactions on Transco where capacity was  
9 released and usable by the acquiring shipper during the review period and found  
10 that DEP made no releases of capacity other than to its affiliate DEC.<sup>19</sup> The  
11 Companies made no other releases of Transco capacity usable by a buyer during  
12 the review period.<sup>20</sup> In Exhibit 5, I provide examples of other electric generators  
13 with Transco capacity that made releases of idle capacity into the secondary  
14 market during the review period. There are hundreds of such transactions, with  
15 durations ranging from one day to the full one year period of the review period.

16 The Companies participate in these secondary markets today; indeed, this  
17 is where they acquired additional winter and non-winter capacity to supplement  
18 their long term capacity, as discussed above. As such, the Companies could have  
19 monetized some of their unused Transco capacity by selling it in the secondary

---

<sup>19</sup> These transactions are noted in the Companies' response to ER 1-6. These transactions are also publicly available information.

<sup>20</sup> Skipping Stone operates Capacity Center, which collects all offer, bid and award data directly from the computer databases of the pipelines and provides that information to its subscribing customers. Capacity Center has a record of every capacity release transaction on all the major pipelines going back more than 15 years and on all pipelines since 2010.

1 capacity release market. In so doing they could have saved ratepayers money with  
2 no degradation of reliability or operational flexibility.

3 **Q: What is your recommendation to the Companies and the Commission on this**  
4 **issue?**

5 A: I recommend that DEP be required by this Commission to monetize its unused  
6 capacity or show why such monetization is impossible.

7

8 **IV. RECOMMENDATIONS FOR ADDITIONAL DATA**  
9 **GRANULARITY AND FOR PROCEDURAL CHANGES**

10

11 **Q: You mentioned previously that certain data deficiencies hindered your**  
12 **analysis. Please elaborate.**

13 A: To assess the sufficiency of existing firm capacity, I need to be able to determine  
14 the actual and expected usage levels of the Companies' combined cycle capacity.  
15 I exclude combustion turbines because in my experience electric utilities seldom  
16 subscribe to firm pipeline capacity to serve peaker units. This is because these  
17 units run at very low annual load factors (2-10 percent or fewer hours per year)  
18 and some peaking units do not run at all in some years.

19 In addition, most combustion turbines have the ability to burn fuel oil  
20 when natural gas is unavailable or more costly. As can be seen by the data  
21 provided in Table 4 (in the Appendix), none of the Companies' peaking  
22 combustion turbine units run solely on natural gas. Thus, in assessing the  
23 Companies' overall gas needs, it is important to know to what extent its  
24 combustion turbines are burning fuel oil instead of natural gas. For this reason, we

1 requested that the Companies provide information as to the fuel used for  
2 generation during each hour that a unit produced electricity.<sup>21</sup>

3 Unfortunately, the flow data provided in discovery did not separate out  
4 combustion turbine gas usage at locations having both combined cycles and  
5 combustion turbines. As a result, for those days where the Companies consumed  
6 gas in quantities exceeding hourly or daily contracted capacity levels, I was  
7 unable to calculate how much of that gas usage was driven by the combined cycle  
8 units versus combustion turbines at the same location.

9 **Q: What would resolve this issue and make capacity sufficiency analysis**  
10 **possible?**

11 A: The Companies could provide, along with the hourly generation of each  
12 separately identified unit (combined cycle and combustion turbine), the type of  
13 fuel used in such hour. That data, in conjunction with hourly gas delivery data,  
14 would make it possible to analyze and assess whether the Companies' firm  
15 pipeline capacity is sufficient to serve its combined cycle units. It should be noted  
16 that Dominion Energy South Carolina does provide such data in a manner that  
17 enables the Commission, ORS, and intervenors to obtain and analyze the hourly  
18 fuel use type.

19 **Q: Do you have a recommendation in this regard?**

20 A: Yes. The Commission should require the utilities in future fuel cases to collect  
21 and provide for each generation unit the hourly generation (MWH), the unit type  
22 (combined cycle or peaking/combustion turbine), and the type and quantity of fuel  
23 consumed by hour.

---

<sup>21</sup> See GML Exhibit 3 (Companies' response to ER 1-5).

1     **Q:     What issues related to the procedures in annual fuel cost proceedings do you**  
2           **want to discuss?**

3     A:     In addition to my recommendations for more granular hourly and fuel use data, I  
4           recommend the Commission allow additional time between the filing date for  
5           Company direct testimony and the deadline for other parties' direct testimony.

6                 In this proceeding, for instance, the Company filed its testimony on April  
7           27, 2020, with the deadline for other parties' direct testimony on May 18, 2020.  
8           Under the Rules of Practice and Procedure, the Companies have twenty days to  
9           respond to Requests for Production of Documents. Even if intervenors were able  
10          to review the Company's testimony and file such requests the following day, the  
11          Company's responses would not be due until the business day before the  
12          intervenor testimony deadline. This short timeframe deprives intervenors of time  
13          to review and incorporate Company responses into testimony and provides no  
14          time whatsoever for follow-up or clarification requests based upon Company  
15          responses. To address this procedural infirmity, I recommend that the  
16          Commission consider extending the time between when Company direct  
17          testimony is due and the deadline for other parties' testimony to 30 days. Such a  
18          modified procedural schedule would allow follow-up requests to be responded to  
19          and for the development of a fuller and more complete record for decision.

20    **Q:     Does that conclude your testimony?**

21    A:     Yes.

**APPENDIX****Table 1: Plant Name Data provided for MWH of production by plant (See Response to ER 1-8)**

PLANT_NAME	UNIT_TYPE
Asheville	Combined Cycle
H.F. Lee	Combined Cycle
Richmond County/Smith	Combined Cycle
Sutton	Combined Cycle
Marshall	Conventional Hydro
Tillery	Conventional Hydro
Walters	Conventional Hydro
Asheville	CT
Blewett	CT
Darlington	CT
Richmond County/Smith	CT
Sutton	CT
Wayne County	CT
Weatherspoon	CT
Asheville	Fossil
MAYO	Fossil
Roxboro	Fossil
Brunswick	Nuclear
Harris	Nuclear
Robinson	Nuclear
Camp Lejeune	Renewables
Elm City	Renewables
Fayetteville	Renewables
Warsaw	Renewables

**Table 2: Plant Name Data provided for allocation of fixed costs of pipeline and LDC charges (See Response to ER 1-11)**

Plant Name
Asheville CT
Asheville CC
Wayne CT
HF Lee CC
Richmond CT
Richmond CC
Sutton CC
Sutton CT
Darlington CT
Richmond - Biogas
Wthspn / Lumberton CT

**Table 3: Plant Name Data provided for hourly flows of natural gas (See Response to ER 1-7)**

Pipeline	Plant Name
TRANSCO	Anson (NCEMC)
PSNC	Asheville
TRANSCO	Belews Creek
TRANSCO	Broad River
TRANSCO	Buck
TRANSCO	Cherokee
PSNC	Cliffside
CGT	Darlington County
PIEDMONT	Fayetteville
TRANSCO	Lee W.S.
TRANSCO	Lincoln
TRANSCO	Richmond County
TRANSCO	Rockingham
TRANSCO	Sutton
TRANSCO	Wayne County

**Table 4: Plant Name Data in the Duke 2019 IRP (including DEP SC) lists the following plants capable of being gas-fired, their capacity and fuels**

Combined Cycle		Winter Summer			Resource	
		Unit	(MW)	(MW)	Location	Fuel Type
Lee	CT1A	225	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	227	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	228	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith 4	CT7	194	154	Hamlet, NC	Natural Gas/Oil	Base
Smith 4	CT8	194	153	Hamlet, NC	Natural Gas/Oil	Base
Smith 4	ST4	182	169	Hamlet, NC	Natural Gas/Oil	Base
Smith 4	CT9	216	174	Hamlet, NC	Natural Gas/Oil	Base
Smith 4	CT10	216	175	Hamlet, NC	Natural Gas/Oil	Base
Smith 4	ST5	248	248	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	224	170	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	224	171	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	271	266	Wilmington, NC	Natural Gas/Oil	Base
Combustion Turbines						
Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	63	50	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	61	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	50	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	60	48	Hartsville, SC	Oil	Peaking
Darlington	6	62	43	Hartsville, SC	Oil	Peaking
Darlington	7	61	47	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	62	44	Hartsville, SC	Oil	Peaking
Darlington	10	65	49	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith 4	1	189	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith 4	2	187	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith 4	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith 4	4	186	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith 4	6	187	145	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	4	49	39	Wilmington, NC	Natural Gas/Oil	Peaking
Sutton	5	49	39	Wilmington, NC	Natural Gas/Oil	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	191	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	195	163	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	30	Lumberton, NC	Natural Gas/Oil	Peaking

Note that the plant names in Table 3 (from ER 1-7) do not distinguish between CC and CT facilities at the same pipeline delivery location. Note also that some of the Table 3 plant names may be synonymous with the plant names in other of the above tables but the time allowed DEP for response to follow-up data requests does not lend itself to resolving such matters before testimony is due.